Scottish & Southern Electricity Networks
TRANSMISSION

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Dear Phoebe,

SSEN Transmission Response: Locational Pricing Assessment Call for Input.

This response is prepared on behalf of Scottish Hydro Electric Transmission Plc (SSEN Transmission), part of the SSE Group, responsible for the electricity transmission network in the north of Scotland.

We welcome the opportunity to provide feedback on Ofgem & FTI's assessment into the potential transition to a zonal or nodal wholesale market. We have provided a high-level view of our initial thoughts whilst considering the views of our stakeholders. Our views are subjective until further modelling and detailed analysis on what the proposed options mean for GB are published. With the omission of 'real life' modelling of the practicalities and implications of the implementation of nodal pricing, it is difficult to fully assess its impacts. With this in mind, we have focussed our response on the potential impact of locational pricing on three core principles. Specifically:

- certainty in renewable generation required to deliver Net Zero,
- certainty in transmission investment to deliver the network required for Net Zero; and
- consumer cost.

As a facilitator in the connection of renewable energy, we have consistently heard strong concerns from our generation customers that TNUoS charging is adversely affecting the investment case for new and existing projects. This is due to high, volatile, and unpredictable costs driven from the current methodology. Given that nodal pricing encompasses TNUoS and is expected to increase the strength of locational signals sent to market, it is with our stakeholder's interests in mind that we consider the impacts of nodal pricing. Any uncertainty for them results in uncertainty for our network development and ultimately costs the consumer.

This is an area in which we are most interested and welcome any further engagement. Should you wish to discuss any aspect of this response please do not hesitate to get in touch.

Yours sincerely,

Andrew Urquhart
Head of Whole System

Annex 1

Question 1 - The key opportunities associated with introducing more granular locational pricing in GB

Perceived Opportunities Associated With Nodal Pricing

We appreciate that there is significant literature surrounding nodal pricing and the perceived benefits, and that it is a market design framework utilised in many jurisdictions around the world. National Grid ESO's Net Zero Market Reform[1] project highlighted a number of potential opportunities and benefits that would arise from implementing more granular locational pricing in GB. One perceived opportunity discussed was investment efficiency and the potential for this to increase a result of stronger economic locational signals. We would like to note that this is an assumption-based assessment, and that it is difficult to evaluate exactly the level of mobility that market participants would exhibit in responding to these signals. The role of government and the direction it would like to set in influencing the generation mix for Net Zero also has the potential to encompass these signals. This would skew the intended signals sent to market from nodal pricing. Other opportunities discussed in the Net Zero Market Reform project such as the potential to reduce constraint costs are also questionable. The increase in constraint costs is not surprising after long periods of significant expansion of generation capacity ahead of commensurate transmission expansion, under the Connect & Manage initiative[2]. Constraint costs will not disappear, they will simply be transferred into wholesale prices.

Reduced costs to GB consumers is another area referenced as an opportunity when introducing more granular locational pricing to the GB market. Although we appreciate certain examples can illustrate this idea, small adjustments to these nodal circuit examples can easily demonstrate scenarios where consumer costs are higher. Inframarginal rents can occur in nodal markets just as they occur under the status quo single national wholesale market. In addition, advocacy that has been presented supporting the idea that nodal markets create increased market liquidity may not account for a variety of factors. Others nodal markets with high liquidity levels such as the PJM Eastern interconnection grid in North America may not necessarily see the same level of liquidity translate into GB markets. The anticipated market behaviour and detail of products that will become available are difficult to predict. Generators "constrained off" under current market design would trade less frequently in a nodal market, given the change to dispatch operations and the move to central dispatch from self-dispatch. The system operator would decide dispatch order, so generators who previously enjoyed freedom in a self-dispatch market would be more restricted in their activity. This would theoretically reduce the volume of hedging instruments traded. These factors coupled with the lack of information available on future GB hedging tools, in terms of the length of time and the suitability of the scope of products, mean that reduced market liquidity is just as plausible. These are some high-level thoughts on opportunities presented in the evidence advocating for nodal pricing within a GB context.

Opportunity to Assess Baseline Alternatives

The assessment into the potential implementation of nodal pricing presents an appropriate opportunity to discuss GB market design options that best facilitate progress towards our Net Zero goals. With an increasing influx of renewable generation anticipated over the coming decades as we transition away from fossil fuel-based electricity, whilst maintaining security of supply, conducting analysis of all potentially viable options for market design will be crucial. We therefore believe that discussions surrounding nodal pricing, such as this Call for Input, create a prime chance to analyse all potential scenarios. One such development that should be considered is how the current market arrangements with a suite of improved alternatives would compare to zonal and nodal options. This would create a counter factual

[1] National Grid ESO: Net Zero Market Reform Phase 3 Assessment & Conclusions - May 2022
[2] Department of Energy & Climate Change: Government Response to the technical consultation on the model for improving grid access - July 2010

alternative and allow for further potential options to be assessed on how best to support delivery of Net Zero, rather than starting with the assumption that more granular locational pricing is the optimal solution.

One of the influencing factors driving National Grid ESO's recommendation to advocate for nodal pricing was concern surrounding the strength of locational signals currently offered to market. Locational signals within status quo market design are managed through Transmission Network Use of System (TNUoS) charges. The current TNUoS methodology has historically created unpredictability and volatility that unfairly skews the market, whilst disincentivising investment in renewable generation in the places that offer the best renewable resource[3]. These issues translate into increased costs for generators and consumers alike, with implications for securing supply chain investment in Scotland. This area has begun to see reform with the launch of Ofgem's TNUoS task force that will begin meeting this summer, where the goal is to address short term volatility within TNUoS charges[4]. It is therefore essential that the impact of this alternative baseline approach is given fair consideration and thinking. Ultimately, alterations to the current market regime mechanisms may offer a much more efficient means to deliver the optimal market design needed to achieve the country's Net Zero ambitions.

Question 2 - The key implementation challenges, risks and mitigations

Net Zero Impact

The economic theory underpinning nodal pricing suggests that north of Scotland generators are expected to clear reduced wholesale prices versus current market arrangements. This would potentially put Net Zero goals at risk. Given the increased load factors and natural resource availability in the north of Scotland, it seems a counterproductive way to explore how to best achieve Net Zero. North of Scotland Future Energy Scenarios (NoSFES) tell us that a significant capacity of renewable generation will be required from the north of Scotland; 24-31GW by 2030 and 49-52GW by 2050 in order for GB to meet its legally binding Net Zero targets[5]. Considering this, we have concerns that the implementation of zonal or nodal pricing may mirror or worsen the current issues of TNUoS which result in high, volatile, and unpredictable costs. If such issues are not addressed through market reform, we foresee this impeding the development of renewable generation in the north of Scotland, where there is rich renewable resource.

As the transmission owner in the north of Scotland, we have an interest here – any uncertainty for future renewable growth, translates as uncertainty for critical network investment. Such uncertainty also increases the risk for renewable developments ultimately increasing costs; in the current energy and cost of living crisis, policymakers should be focused on providing stability and investor confidence to keep costs of a capital-intensive energy transition at a minimum. In the context of decarbonisation, this provides challenges at a time when certainty, accelerated delivery and a strategic plan is needed more than ever if the UK is to meet its legally binding climate and renewable energy targets at scale, pace and in the most economically efficient way. Scottish government has its own goals for reaching Net Zero by 2045[6], so any market signals that incentivise opposite movements will be at odds with government policy and are likely to create political resistance. This risk runs alongside the "post code lottery" concept associated with nodal pricing, where GB consumers receive differing prices depending on location.

The current evidence analysing nodal pricing within a GB context takes note of the potential detrimental impact on north of Scotland wholesale prices. One of the perceived counter measures to deal with this issue and to reassure current and future investment is the use of hedging mechanisms such as Financial Transmission Rights (FTRs). It is clear from the evidence presented in National Grid ESO's Net Zero Market Reform project that there is significant progress still to be made with this concept. Details such as how the financial instruments would be managed and distributed, or who would be deemed most suitable to operate the auction house have not yet been considered. If it is sensible to

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[3] SSEN Transmission: Transmission Charges, An overview of charges for use of the GB transmission system - February 2021
[4] Ofgem: TNUoS Task Force - May 2022
[5] SSEN Transmission: North of Scotland Future Energy Scenarios - May 2022
[6] Scottish Government: Climate Change Plan - May 2021

assume that National Grid ESO will function as the auction house that completes the exchange of FTR's, then we believe this should be considered within the ongoing Future System Operation (FSO) consultation[7].

There is also minimal acknowledgement of the extensive level of complexity associated with building a new trading market from the ground upwards. We would anticipate that ensuring the correct mechanisms are in place to facilitate free trading FTR's would be just as complicated as the modelling of nodal prices. We would also expect to see increased analysis surround the practicalities of what FTR's would look like in a GB context in terms of length; if they are only sold on one year ahead terms then liquidity levels would remain low. Furthermore, the shape of product will be crucial given generators will require specific products that match the profile of their expected output. A fair comparison across other markets with transmission rights trading would be beneficial. Although PJM Eastern interconnection markets in North America are lauded for the liquidity levels they achieve, MISO the Midcontinent market in North America has significantly reduced liquidity relating to FTR's in comparison[8]. If this is to be the mechanism to appease concern of investment within the north of Scotland in particular, then we would welcome further analysis in this area.

It is important to also consider the impact that nodal pricing may have on distribution, given the key role that distribution will play in facilitating demand side response and retail innovation required to deliver Net Zero. If the implementation of nodal pricing means that coordination between markets at different voltages is required, the deliverability of such a task must be fully explored. Switching from existing zonal areas to a nodal system would require a completely new system for identifying and allocating MPANs by location. This would create a significant impact on the retail sector and the associated administration systems. Industry reviews currently ongoing such as faster switching programmes and market wide half hourly incentives would also be impacted. This would create a further level of complexity to be analysed when completing a holistic review of nodal pricing and its suitability to best facilitate Net Zero.

The concerns noted above are further heightened when considering the ScotWind announcements from earlier in this year. The result of ScotWind was a pledge of a further 25GW from the north of Scotland over the coming decades as a result of Crown Estate Scotland's land leasing process[9]. Investment decisions for the north of Scotland were based on current market design alongside other components such as land, resources, consenting and capacity. When considering market reform, it is important that these elements are considered holistically, and full consideration is given to creating a market where areas with the best renewable resource are incentivised to utilise the abundance of natural resource availability.

Future Transmission Investment and Constraint Management

The rising cost of constraints has consistently been touted throughout the Net Zero Market Reform process as a decisive factor in advocating for nodal pricing. This provides a valid opportunity to reflect as to how as industry we have arrived at this scenario, focussing on lessons learned that can be applied to future market design. Specific regards should be given to rising levels of constraints, Connect and Manage and the process for green lighting new transmission investment. It is not surprising that in a period of significant expansion of generation capacity ahead of transmission expansion, constraint costs are rising significantly and consequently driving Balancing Service Use of System (BSUoS) costs upwards[10].

A key implementation challenge we foresee will be alterations made to the methodology used by National Grid ESO and Ofgem for green lighting new transmission investment in a nodal market. Within current market design, there are several key documents associated with new transmission investment: Network Option Assessment (NOA), Electricity Ten Year Statement (ETYS), Offshore Transmission Network Review (OTNR) & Holistic Network Design (HND). Each of these influence decisions that are made to ensure the optimal development of the transmission network to deliver Net

[7] Department for Business, Energy & Industrial Strategy: Joint Statement on the Future System Operator - April 2022
[8] London Economics International: Review of PJM's Auction Revenue Rights and Financial Transmission Rights – December 2020
[9] Crown Estate Scotland: ScotWind offshore wind leasing delivers major boost to Scotland's Net Zero aspirations - January 2022
[10] Cornwall Insight: "Fixing" Balancing Costs - March 2022

Zero. It is therefore crucial that the interdependencies and wide-reaching impacts of the afore mentioned mechanisms for transmission investment will be given extensive consideration within any new market design proposals. The current cost benefit analysis compares the cost of new network build versus the benefits created over the lifetime of a new asset, such as the pass-through impact on redispatch or constraint management[11]. Given the impact on this area driven from the fundamental changes associated with nodal pricing's implementation, we are concerned as to how this will be captured in the updated methodology for transmission investment assessment cases. We would also expect inputs to the afore mentioned cost benefit analysis process to change, making modelling more complicated. This is due to the arrival of new inputs that will need to be captured, such as the forecasting of future price spreads at different nodes across GB. With this in mind, it is essential for full transparency regarding how the methodology and decision-making process underpinning decisions for new transmission investment will be applied in a nodal market.

In a nodal system, the cost associated with constraints does not disappear. Instead of being levied to consumers through recovery mechanisms such as BSUoS, they will be incorporated into wholesale spot prices that generators can offer. The cost of constraints is therefore built into wholesale prices. As a result, any planned transmission infrastructure investment will have the potential to materially impact the wholesale prices that generators can provide, assuming transmission investment will alleviate constraint levels. This is an area that will need further consideration when assessing the impact of changing the process for green lighting transmission investment. Issues such as outages, faults, planned maintenance and unexpected adverse weather conditions all have the potential to impact the capacity of the transmission system at any time. These factors can further exacerbate constraint levels at certain points on the system, impacting the wholesale prices available at different nodes within the GB system. We would expect that further analysis will be conducted into this area to ensure that all potential passed through impacts have been accounted for, and that maintaining the reliability of the network is given sufficient consideration.

Deliverability

We agree with National Grid ESOs assessment that the deliverability of nodal or zonal pricing would present great challenges. Considering the time scale associated with other industry reform work streams such as the Access & Significant Code Review, which is yet to complete and has created new Ofgem works streams as a result[12], we see implementing nodal pricing as taking a significant length of time. Given the scale of change required to facilitate a nodal market and the length of time that would be required, we are doubtful if such a radical change will incentivise or provide stability for renewable investment and network investment. We believe that the current timeline for delivery estimated in the Net Zero Market Reform project, by 2027, is not fully aligned with the time that industry anticipates such a change would take. There will be the likely risk of a variety of factors such as legal challenges, procurement issues and general delays to the process.

Another aspect of deliverability we feel creates significant risk to industry is the future of TNUoS within a nodal market. There is currently limited available evidence as to what would happen to TNUoS given that nodal pricing encompasses the locational signal created by TNUoS. If it is assumed that generation revenue recovered through locational TNUoS shifts to revenue earned from the wholesale market then there is range of scenarios that must be properly tested, benchmarked and analysed. Possibilities such as using the congestion rents earned by National Grid ESO as the settler of market participation through central dispatch in a nodal system, or the potential revenue created from financial surplus acquired from facilitating the auction of FTR's are complex alternatives that will require significant forecasting and resource. The recovery mechanisms for collecting regulated allowed revenue as a transmission owner is therefore open to extensive risk. We believe that reforming TNUoS after the implementation of nodal pricing will be a vast task and is another factor as to why the current deliverability timelines do not appear completely representative of the scale of challenge.

[11] National Grid ESO: Networks Options Assessment Methodology - July 2021
[12] Ofgem: Access and Forward-Looking Charges Significant Code Review Final Decision - May 2022

We also foresee the implementation of nodal or zonal pricing coming at a significant financial cost, with significant investment into new IT systems being required alongside new analysis, forecasting and risk products. Given that nodal pricing facilitates a move back to central dispatch, this would mean the need for a material change to the central IT architecture to account for closer integration between systems supporting the market and those managing networks & the supporting operations. The switch from self-dispatch to central dispatch is not one to be taken lightly, given the anticipated impact on the operation of the day ahead market, intra-day market and the balancing mechanism. Furthermore, the Net Zero Market Design project is only one of several ongoing industry reviews; Energy Code Review, TNUoS Task Force, British Energy Security Strategy, Offshore Transmission Network Review, Future System Operation and the Access SCR are to name a few. Decisions made within these reviews will likely directly relate to the work undertaken surrounding market design. Any assessments undertaken must consider the links, potential unintended consequences and risks associated with any recommendations which are as a result of this project. This will also be important to ensure maximum efficiency and appropriate use of industry resources given the increased need the move away from fossil duel dependant electricity and with the current cost of living crisis.

International Examples

We note that throughout the material used in the Net Zero Market Reform Project, international markets are often used as a comparison or benchmark as to why nodal pricing should be used within a GB context. We would like to note our concerns regarding using certain examples, as although we appreciate that there are similarities in many jurisdictions, we feel it is vital to also be conscious of the differences. Many jurisdictions that have nodal pricing market design have unique circumstances which must be respected when conducting analysis, and further increases the feeling within industry that more GB specific nodal pricing analysis is required.

New Zealand is a market that is often touted as an example of a successful nodal energy system. We agree on certain similarities; both are island-based jurisdictions, both have comparable demand to generation flows with New Zealand transporting hydro power from the south island up through HVDC links and into north island demand centres, and both are aiming for ambitious Net Zero renewable targets. However, we feel it is important to also highlight the differences. New Zealand moved to nodal pricing in the 90's as part of a switch from nationalisation to privatisation and have been working on tweaking their market design over the last 30 years. The process throughout the 90's was extensive; preceded by broad legislative issues the reformed wholesale market finally began trading in 1996. It wasn't until 2004 that the appropriate regulatory bodies were arranged and resourced to regulate and properly facilitate the new nodal market[13]. The extensive bureaucratic regime required raises our earlier concerns surrounding the deliverability presented for implementing nodal pricing within a GB regulatory framework. GB does not have the time for trial and error approaches to market design given the impending closeness of our Net Zero targets.

Further, the history of New Zealand's generation mix differs greatly from GB. New Zealand had an extensive renewable hydro history prior to their switch to nodal pricing. The large injection of renewables was not new, unlike the GB scenario that is moving away from a gas and coal-based system of the last several decades. HVDC links are also energized within the country, as well as a sufficiently sized ac network, between the north and south islands. New Zealand has the network to provide connection capacity to new applicants, as a result the electricity system does not suffer from extensive constraint problems that we do in GB.

The monopoly structure of national infrastructure is also handled different to that of GB. For example, the electricity system operator and transmission owner equivalent are the same singular organisation, Transpower. As a result of the synergy created from this arrangement, New Zealand are able reap benefits of leaner and quicker processes for green lightning new transmission infrastructure. In our discussions with Transpower, they informed us that they have a proactive approach to transmission investment. Anticipated future impacts on constraints and power flows as the result of generation and demand are accounted for within their system planning in order to ensure the network that best

[13] Ministry of Business, Innovation & Employment: Chronology of New Zealand Electricity Reform - August 2015

facilitates real life power flows are progressed towards[14]. Given that historically network investment has kept pace with generation and demand developments, they have little problems with constraint management. This is in contrast to the reactive approach that has been applied in GB, where the Connect & Manage method has been championed over the last few decades leading to the constraint issues currently present within the GB market. There are useful lessons to be learned from other jurisdictions, but they should not be viewed as definitive with regards to their influence on our energy transition given the difference in each jurisdiction's electricity systems.

Risk and Uncertainty During Critical Period & The Associated Cost to Consumers

As touched upon at various points throughout our feedback, we feel it necessary to convey our concerns surrounding the increased risk in investment in renewable generation during one of the most crucial periods of GB ensuring a Net Zero future. The UK Government has pledged to be a Net Zero electricity system by 2035[15], with the full of GB aiming to achieve Net Zero by 2045 / 2050 as mentioned previously. In order to achieve these goals, there needs to be certainty and guarantees offered for investment decisions being made right now. The threat of increased uncertainty and risk has the potential to threaten sufficient progress towards these goals.

Nodal pricing ultimately will present a much more complex and volatile system. It is likely to increase risk that will be reflected in an increased cost of capital. Increasing risk on generators and moving constraint costs from consumer bills to generators wholesale prices will penalise renewable generators who are actively contributing to Net Zero goals. This risk premium combined with the impact of increasing the potential cost of capital poses a concern over the investment case for capital-intensive large-scale projects that will provide the backbone of the future GB Net Zero generation mix. The impact of increased risk and cost of capital further raises concern if nodal market design is the most appropriate means for reaching Net Zero at the lowest cost to consumers.

Impacts on current government policy direction for incentivising renewable generation such as Contracts for Difference (CfD) is another source of risk associated with the implementation of a nodal pricing system. The compatibility of CfD with a nodal system would require complex analysis that has far reaching impact, given the predicted difference in wholesale prices between the north and south in GB. Modelling the difference in spot prices at each node on the GB system into current CfD procedures managed by the Low Carbon Contracts Company (LCCC) is no easy task and must be given the appropriate resource. Amended CfD policy developments or completely new support mechanisms unknown to industry may emerge creating further uncertainty during a critical period. This is an additional example of complex reform that will require significant analysis given the highly material and commercial impact associated with CfD and central government renewable policy.

Uncertainty and complexity created as a result of nodal pricing has the potential to impact the full energy chain: the decisions made now on deciding the most appropriate market design for decarbonisation and achieving Net Zero will ultimately pass through to retail suppliers and GB consumer bills. The severity of the change and difficulty associated with liquidity and level of sophistication required with hedging could create market conditions that many retailers are not equipped to deal with. Increased complexity in an already intricate industry may act as a barrier for innovative market disruptors and technologies. Additional convolution also hinders market access for smaller industry players such as community groups which will be critical in the implementation of decentralised sources of energy to support the transition to Net Zero. This is especially true given the significant level of supplier failures over the previous 12 months, where record numbers of suppliers have left the market[16]. These factors will ultimately all filter into GB consumers bills, with the various levels of risk described above creating uncertainty for investment in renewable generation and network investment, creating the potential for increased consumer cost.

[14] Transpower: NZGP1 Scenarios Update - December 2021
[15] Department for Business, Energy & Industrial Strategy: Plans unveiled to decarbonise UK power system by 2035 - October 2021
[16] Oxera: Review of Ofgem's regulation of the energy supply market - May 2022

Question 3 - The proposed approach to modelling zonal and nodal market design

Data Sensitives and Forecast Accuracy

We welcome the modelling FTI & Ofgem are producing into nodal pricing within a GB context and offer the below feedback to bets help contribute towards a model that is as representative as possible. With reference to material from workshop 1 we believe there to be several concerns with the proposed approach to modelling. Regarding the transmission capacity section, the modelling methodology indicates the intention to use the current NOA & ETYS documents. However, these documents do not account for the ScotWind auction results which is anticipated to add 25GW of additional renewable generation from the north of Scotland over the coming decades. Given the scale and impact associated with ScotWind, it is essential that the influence it is predicted to have on power flows is accounted for and what this means for the associated transmission network investment.

As mentioned in our answer to question 2, we would like to note our concerns regarding the future of transmission investment and how this is predicted to be modelled. Given that a theorised benefit of nodal pricing is that constraint levels are expected to decrease, we would seek to receive assurances into how this will be predicted and modelled. Current key documents such as NOA and ETYS assume status quo market design arrangements, so it is vital that the impacts of any new market design arrangements on how transmission infrastructure capacity is to be modelled is accurate. The potential for inaccuracy in this area could lead to the same issues that are currently experienced within industry in relation to TNUoS. The 5-year ESO TNUoS future charges modelling[17] carried out is often not accurate when carrying out ex ante exercises comparing forecasts versus actual costs. We are keen that we do not end up in the same modelling scenario that has occurred with TNUoS.

One aspect that we would been keen to see addressed is the transparency of data and the revisiting of previous forecasts, which will allow for the model to remain as accurate as possible. The NOA 6 constraint cost by FES scenario from 2021 to 2041 (slide 22 of workshop 1 content) published by National Grid ESO[18] is often used as an example of predicted constraint costs. It would be beneficial to see this turn into an annual publication in the future, allowing for a comparison exercise of how accurate the forecasts have turned out to be and crate tangible evidence and increase the quality of data being input to the model. Accompanying this, full transparency behind calculations relating to constraint management would be beneficial for industry. This is especially true given the inaccuracy of previous forecasts in areas relating to constraints, such as BSUoS forecasts vs actual BSUoS costs over the previous 12. We welcome any levels of increased transparency within the data relating to the nodal pricing modelling and constraint cost benefit analysis.

In addition, we note that in the generation capacity build out section of the modelling methodology, that build out is to be based upon using Future Energy Scenarios (FES), in particular the System Transformation FES scenario. We appreciate that the FES is a useful and widely acknowledged industry baseline for making forecasts. However, it does not consider recent developments such as ScotWind and therefore raises questions around the representation and accuracy it will provide as an input. Given that one of the core principles of nodal pricing is to incentivise generation investment in different locations, and that this will not be captured in the FES input data, we would like to seek reassurances that potential future scenarios would be incorporated into modelling methodology. FES assumes current status quo market design, therefore reducing the quality of the forecast and its level of representation on what nodal market modelling would translate into.

[17] National Grid ESO: TNUoS Tariffs Five Year View for 2023/24 – 2027/28 Webinar - April 2022
[18] National Grid ESO: Net Zero Market Reform Phase 3 Conclusions - March 2022